CHARACTERIZING NATURAL FRACTURES AND THEIR INTERACTIONS WITH HYDRAULICALLY INDUCED FRACTURES

Charlotte Beran Amandes

Engineering Honors
The University of Texas at Austin

May 2018

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Mukul Sharma, Ph.D.
Petroleum & Geosystems Engineering
Supervising Professor

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John Foster, Ph.D.
Petroleum & Geosystems Engineering
Second Reader

Abstract

Natural fractures are preexisting micro-cracks and fissures that can have a critical impact on hydraulic fracture treatments in shales. Most shale formations contain natural fractures, but the characteristics of these natural fractures can vary significantly. For example, the natural fractures in the Barnett Shale are mostly narrow, long, and sealed with calcite cement. The natural fractures in the Wolfcamp Shale are much more heterogeneous as a whole, but tend to be clustered in similar groupings based on the lithology of certain areas of the formation. The creation and development of natural fractures prior to any hydraulic fracturing treatments is primarily a function of mineralogy, total organic carbon, and in-situ stresses. During hydraulic fracturing treatments, certain characteristics, such as the relative angle between the natural and hydraulic fractures, the length of the natural fractures, the differential stress of the formation rock, and certain completion design variables, will determine how the natural and induced fractures interact and create a fracture network. The presence of natural fractures can have a positive effect on the ultimate hydrocarbon recovery in some cases. Natural fractures provide accumulation space and travel pathways for hydrocarbons, which is critical in low porosity and low permeability shales. However, natural fractures can result in higher rates of fluid leakoff, which will result in less efficient hydraulic fracture treatments overall. Also, natural fractures can provide an undesirable connection to water accumulation, which can negatively impact the economics of a well because of the disposal costs associated with water production.

Acknowledgments

I would first like to thank my supervisor, Dr. Sharma, for all of his time and assistance with this undertaking. I am extremely grateful for his willingness to oversee my work and connect me to a project where I was able to learn so much. I would also like to thank my second reader, Dr. Foster, for dedicating his time to helping me with this project. I would particularly like to thank the researchers I had the opportunity to work with for all of their help. Ripudaman Manchanda helped explain fracture theory and defined relevant variables that assisted me in my understanding of this project. Ajeetha Kamilla provided me with access to and thoroughly explained the program I used as a model, and greatly assisted me in articulating my ideas for the interface I worked on. I am especially grateful to Kaustubh Shrivastava, who took the time to explain the program he is creating to me, and allowed me to be a part of its design and testing. I also want to thank Dr. Julia Gale, of the Bureau of Economic Geology, for taking the time to meet with me to discuss my research and answer my questions. Finally, I would like to thank the staffs of the Plan II Honors Program and Engineering Honors for their assistance during this process.

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Characterizing Natural Fractures and Their Interactions with Hydraulically Induced Fractures

Over the last fifteen years, hydraulic fracturing has become the critical technology for optimizing oil and gas production in the United States. Hydraulic fracturing has allowed operators to produce from shale reservoirs that were previously not considered economically viable. The relative cost and reliability of hydrocarbons compared to other energy sources ensures the value of shale reservoirs for the foreseeable future (King, 2012). However, as operators continue to develop these reservoirs, more data on the preexisting features of these shales will become available. New data presents new opportunities for operators and researchers to learn how to most efficiently optimize production from shales.

Most shale formations contain natural fractures (Gale, 2008). Because of the high overburden pressure and plastic nature of shale reservoirs, these natural fractures are often closed (Sunjay, 2012). In some cases, however, natural fractures are open and act as additional storage space for hydrocarbons, and increase the overall porosity of the reservoir. When wells are hydraulically stimulated, the hydraulic fractures connect to the natural fractures and can re-open them, creating a network of induced and natural fractures (Sunjay, 2012). The development of the fracture network depends on the preexisting natural fractures and the completion parameters chosen (Song, Jinzhou, & Yongming, 2014). In many cases, the presence of natural fractures can have a positive impact on hydrocarbon recovery, but in other cases, natural fractures reduce the economic viability of a project by connecting the reservoir with a water source through faults. An understanding of the natural fractures in the reservoir rock is therefore critical to enhancing the effectiveness of hydraulic fracturing in unconventional formations.

This thesis seeks to address those geologic and physical factors that promote the development of natural fractures. In addition, this thesis details how hydraulically induced and natural fractures interact with each other in different ways, producing different fracture networks as a result. Specific attention is dedicated to the Wolfcamp Shale in the Delaware Basin. Finally, this thesis also contains a section detailing the author's involvement in creating a graphical user interface (GUI) for a hydraulic fracturing software that accounts for the presence of natural fractures.

Overview of Natural Fractures and Fracture Theory

Natural fractures are small fissures or micro-cracks in a rock formation that form as a result of the geomechanical properties of the rock, and not because of any sort of human interference. The rock failure that results in the formation of natural fractures is similar to the failure that results in hydraulically induced fractures. In both cases, the changes in pore pressure of the rock cause the failure envelope to be exceeded, resulting in fractures (Mason, 2016).

This section will explore the different factors that affect how natural fractures develop, and will discuss the impact those natural fractures have on the reservoir as a whole. In some cases, natural fractures will have a net positive impact on the total hydrocarbon recovery, but in other cases natural fractures can adversely affect how much oil and gas can be recovered.

Variables that Impact Natural Fracture Formation

There are multiple properties of the rock formation that will affect how natural fractures are created and subsequently develop. These properties can be specific to the individual formations and help explain why natural fracture orientation, length, and arrangement can vary from formation to formation.

Mineralogy. One of the main factors that controls fracture development is mineral composition (Ding et al., 2012). The mineralogy of the formation has a critical impact on whether and how natural fractures will form and grow because mineralogy has a strong effect on the brittleness of reservoir rocks. Mineralogy determines the values of parameters like Young's modulus and Poisson's ratio, which are used to characterize the strength of rocks and their response to deformation. Geologists have identified a correlation linking both natural and induced fracture development with the volume of brittle minerals present in the rock (Ding et al., 2012). Minerals like quartz and feldspar are considered brittle because of their high silica content. In addition, calcite is considered brittle because of the presence of carbonates. Therefore, greater quantities of silica and detrital calcite in a rock make the rock more brittle (Gale, Laubach, Olson, Eichhubl, & Fall, 2014).

The brittleness index defines the mineralogy in quantitative terms, and thus allows geologists and others to better compare different reservoir rocks. According to Herwanger, Bottrill, and Mildren (2015), one such definition for brittleness index (BI) uses the relative volumes of quartz, calcite, and clay:

$$BI = \frac{V_{quartz}}{V_{calcite}+V_{clay}+V_{quartz}} \qquad \text{Equation 1}$$

Another source defines brittleness index similarly (Mason, 2016):

$$BI = \frac{V_{calcite}+V_{quartz}}{V_{calcite}+V_{clay}+V_{quartz}} \qquad \text{Equation 2}$$

The total volume of clay is in the denominator of both equations for brittleness index. The presence of clays tends to indicate that rocks are more ductile. The more clay-rich varieties of shales are sometimes devoid of natural fractures (Gale, Laubach, Olson, Eichhubl, & Fall, 2014). These shales may develop induced fractures as a result of completions operations, but preexisting natural fractures are likely scarce based on the shale lithology.

A third definition for brittleness index states that rocks with a high brittleness index value have a high Young's modulus and a low Poisson's ratio (Herwanger, Bottrill, & Mildren, 2015). Thus, more brittle rocks have higher Young's moduli and lower Poisson's ratios (King, 2010).

Young's modulus (E) is defined as the ratio of stress to strain under uniaxial loading. Poisson's ratio (v) is defined as transverse strain to axial strain. The relationship between rock brittleness and Young's modulus and Poisson's ratio is not limited to shales; sandstones follow the same correlation patterns. Research in more gaseous shale formations such as the Barnett, Eagle Ford, and Marcellus has shown that shales can have distinctly lower Young's modulus values than the sandstones layers around them, and these shales have either lower natural fracture abundance or no natural fractures as a result (Gale, Laubach, Olson, Eichhubl, & Fall, 2014). There appears to be a positive correlation between Young's modulus and natural fracture frequency, and an inverse relationship between Poisson's ratio and natural fracture frequency.

Total Organic Carbon Content. A second factor that controls natural fracture development is the total organic carbon content of the reservoir. The total organic carbon (TOC) of the reservoir measures the amount of organic carbon trapped in the rock and is typically expressed as a percent. The TOC has an obvious correlation with the total amount of hydrocarbons stored in the rock, but TOC also influences natural and induced fracture development. There is a positive correlation between fracture development and TOC (Gale, Laubach, Olson, Eichhubl, & Fall, 2014). Ding et al. (2014) explain this correlation in noting that a higher TOC indicates that there are more ultra-micro pores present in the shale matrix. The more pores in the rock, the more micro-fractures can be generated, because a more porous rock is weaker and more susceptible to failure than a more cohesive rock. In addition to its correlation with high fracture abundance, a high TOC is also related to greater rates of catagenesis, which is the process by which kerogen is converted to hydrocarbon (Gale, Laubach, Olson, Eichhubl, & Fall, 2014). The following figure was created with data from older gaseous shale plays, and shows the positive relationship between TOC and fracture development.

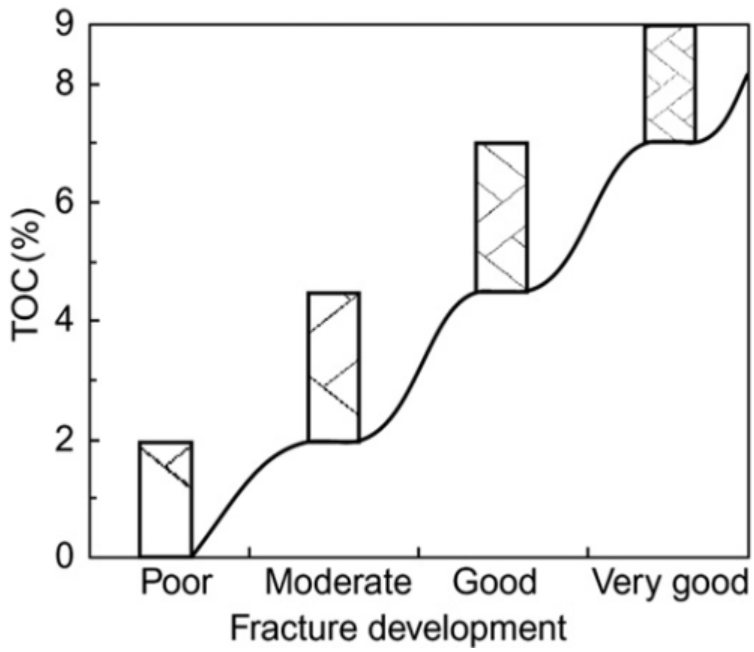

Figure 1. Relationship between fracture development and TOC (Ding et al., 2012).

Orientation Relative to Stresses. The conventional belief is that natural fractures open parallel or nearly parallel to the direction of the maximum horizontal compressive stress, S_{Hmax} (Laubach, Olson, & Gale, 2004). This reasoning is logical given that natural fractures oriented parallel to S_{Hmax} would provide the least inhibition to reservoir fluid flow due to the orientation of stresses around them. According to this assumption, the stresses would then cause the fractures that are not parallel or near-parallel to close (Laubach, Olson, & Gale, 2004). The natural fractures can be oriented in any direction, but the direction of S_{Hmax} will thus dictate whether or not the natural fractures will be open and linked to the fracture network. However, core studies and observations of azimuthal shear wave velocity anisotropy by Laubach, Olson, and Gale (2004) have shown that the orientation of S_{Hmax} has a minimal effect on whether or not natural fractures are open. On a more local scale, the orientation of the stresses may have a greater impact on the open or closed quality of natural fractures, but when looking at a field as a whole, S_{Hmax} is less important.

As established previously, natural fractures and hydraulically induced fractures are both caused by changes in pressure that result in rock failure. Therefore, if a formation forms natural fractures easily due its rock properties, this same formation will be more responsive to hydraulic fracturing operations as well. For example, a shale with a high total organic carbon percent and high relative amounts of minerals like quartz, feldspar, and calcite will be more brittle, and will have a lower Poisson's ratio and a higher Young's modulus. As a result, this shale will not only be more conducive to natural fracture development, but it will also respond more optimally to hydraulic fracture treatments (Ding et al., 2012). In addition, a rock with a high degree of natural fractures is more likely to respond to hydraulic fracture treatments because the natural fractures weaken the overall strength of the reservoir rock.

Assessing the Effects of Natural Fractures

Natural fractures can have positive and negative impacts on the effectiveness of well completions. While natural fractures can improve porosity and permeability, facilitating an increased hydrocarbon recovery, natural fractures can also connect wells to water sources, and can trap and divert frac fluid.

Storage. Natural fractures, when opened, hold reservoir fluids and thus act as storage. Natural fractures help increase the total free gas accumulation in shale by providing migration pathways and accumulation space for hydrocarbons and formation water (Ding et al., 2012). In this way, natural fractures complement the intergranular porosity of the reservoir (Curtis, 2002). Typically, the storage capacity of natural fractures is considered beneficial because the natural fractures are more porous than the shale itself. Thus, if the natural fractures become connected to the wellbore through hydraulic fracturing, more recovery can be expected. However, in cases where the natural fractures are too large relative to the reservoir rock, the hydrocarbons can dissipate, and thus production will be adversely affected (Ding et al., 2012). This problem is more pronounced in more gaseous reservoirs.

The storage capacity of natural fracture systems is highly variable from formation to formation. The size and shape of the natural fractures plays a role in determining their storage potential. For example, narrow natural fractures that are sealed with a calcite cement, like those in the Barnett Shale, do not provide any storage or improved permeability unless reactivated by hydraulic fracturing (Gale, Laubach, Olson, Eichhubl, & Fall, 2014). On an extremely localized scale in the Barnett, the rare larger and open natural fractures would enhance permeability and serve as storage (Gale, Reed, Becker, & Ali, 2010).

Impact on Fluid Leakoff. Research by Britt, Hager, and Thompson (1994) has shown that the presence of natural fractures can have an adverse effect on hydraulic fracturing treatments due to the resulting increase in fluid leakoff that occurs in naturally fractured reservoirs. The increased fluid leakoff is considered a detrimental impact of natural fractures because higher fluid leakoff rates result in less efficient hydraulic fracturing treatments.

The reservoir rock permeability, the reservoir fluid compressibility, and the fracture fluid itself affect fluid leakoff in conventional reservoirs. However, in naturally fractured reservoirs, the natural fractures are the dominating factor that controls fluid leakoff. Hydraulic fracturing in reservoirs with natural fractures is less predictable because the extent to which the natural fractures affect leakoff varies with stress and net pressure (Britt, Hager, & Thompson, 1994). Studies have shown that the fluid leakoff to natural fracture systems can be up to fifty times greater than fluid leakoff to the rock matrix, though the choice of frac additives can mitigate these losses (Britt, Hager, & Thompson, 1994). Knowledge of the natural fracture systems is critical to being able to reduce fluid leakoff. For example, if the stress level at which natural fractures open is known, the net treating pressure can be monitored to prevent the unstable natural fracture growth and resulting fluid leakoff (Britt, Hager, & Thompson, 1994). The effects of natural fractures on fluid leakoff highlight the need to better understand natural fracture systems as a whole.

Enhancing Production. In many cases, the presence of natural fractures will have a positive impact on net hydrocarbon recovery. Natural fractures can provide migration pathways and accumulation space for hydrocarbons (Ding et al., 2012). When hydraulic fractures connect to natural fractures, these hydrocarbons can better move through the formation to the wellbore, increasing production. Because shale reservoirs have such low permeability values, any natural fractures that provide a pathway for hydrocarbons can increase recovery.

The impact of the natural fractures is partially dependent on whether the natural fractures are opened or closed. Open natural fractures can enhance both the reservoir quality and completion quality of certain areas of the formation (Li, 2014). The reservoir quality is determined by porosity, permeability, pore pressure, and total organic content, all variables that are determined by the formation itself, independent of any operations. Because open natural fractures enhance porosity and often permeability, natural fractures thus positively impact reservoir quality. Completion quality is essentially defined as the ability to create a large surface area within the fractured formation (Li, 2014). Closed or sealed natural fractures can enhance completion quality, as these fractures are reactivated during the completion process.

Additionally, even closed or partially cemented natural fractures can have a positive effect on permeability. These natural fractures can still have a permeability that is up to three orders of magnitude greater than that of the shale matrix because of the low permeability of shales (King, 2010).

Natural fractures are particularly important during primary recovery, but the enhanced permeability created by these fractures is relevant during secondary and tertiary recovery as well. The fractures, either induced or natural, that transport the most injected water or enhanced oil recovery substance during these operations will also transport the most reservoir fluids (Gong & Rossen, 2017). Because of their role as accumulation space for hydrocarbons and their role in subsequent operations, natural fractures are important during all stages of recovery.

However, natural fractures can have an adverse effect on hydrocarbon production as well. Ding et al. (2012) argue that when natural fractures are too large, natural gas can be dissipated through these fractures, reducing the overall amount of gas in place in the reservoir. Natural fractures can also increase net levels of water production by better linking aquifers or other water zones with the wellbore (Li, 2014). Increased water production is a negative side effect because operators then must pay to dispose of the produced water. Operators should avoid spacing their perforation clusters near areas where water zones have been identified, or where there are believed to be faults that run through these water zones, because natural fractures can help further link the water with the hydrocarbon-rich areas of the formation that the operators are attempting to access (Li, 2014). The potential downsides of natural fractures, particularly with regard to increased water production, further highlight the importance of having information about the location of a formation's natural fractures.

Interactions between Natural Fractures and Hydraulic Fractures

In addition to understanding those factors that affect natural fracture development and assessing the positive and negative impacts natural fractures can have on production, it is also valuable to know specifically how hydraulic fractures interact with natural fractures. A better understanding of the resulting hydraulic and natural fracture network can help optimize production and make completions more efficient (Khelifa, Zeddouri, & Djabes, 2014). The intersection of natural fractures and hydraulic fractures controls the formation of the fracture network (Ren, Zhao, & Hu, 2014). Hydraulic fractures are most effective when they "cross and connect" natural fractures, but there are multiple ways natural fractures and hydraulic fractures will interact (Blanton, 1982).

When hydraulic fractures intersect natural fractures, there are three potential extension paths. In some cases, the hydraulic fracture will cross the natural fracture and continue in its original direction without any significant deflection. In other cases, the hydraulic fracture will intersect the natural fracture and then extend along the natural fracture, until the hydraulic fracture emerges at the natural fracture's tip. This case can also be described as fracture arrest (Rahman & Rahman, 2013). In the third case, which is a combination of the two previous cases, the hydraulic fracture will intersect the natural fracture and extend along the natural fracture, until the hydraulic fracture emerges from a weak point of the natural fracture that occurs before the natural fracture's tip (Wu & Olson, 2014; Ren, Zhao, & Hu, 2014). Natural fracture configuration, the relative angle between the natural fracture and the hydraulic fracture, the length of the natural fracture, the differential stress, and the injection rate were all found to have an impact on how a hydraulic fracture might interact with a natural fracture (Wu & Olson, 2014; Rahman & Rahman, 2013).

Natural Fracture Configuration

For cases where a hydraulic fracture is perpendicular to two parallel natural fractures, and is located at equal distances from each natural fracture, the induced fracture will move symmetrically in both directions from injection point to the hydraulic fracture tips. For these cases, the width profile and net pressure distribution will be equal at each hydraulic fracture tip

(Wu & Olson, 2014). In addition, if the hydraulic fracture cannot initially cross either natural fracture in these cases, the "pressure inside the hydraulic fracture [will build] up until natural fractures fail" (Wu & Olson, 2014).

For those cases where a hydraulic fracture is perpendicular to two parallel natural fractures, but the injection point is located closer to one natural fracture than the other, the width profile and the net pressure distribution will initially both be greater at the hydraulic fracture tip that intersects the closer natural fracture (Wu & Olson, 2014). In these cases, the growth of the hydraulic fracture tip that first encounters a natural fracture will then decrease until the opposite hydraulic fracture tip encounters a natural fracture, due to the distribution of pressure within the hydraulic fracture. The hydraulic fracture will therefore propagate more in the direction toward the more distant natural fracture. Once both hydraulic fracture tips intersect natural fractures, fluid will flow into both fracture tips and the pressure at the first tip, located at the closer natural fracture, will increase (Wu & Olson, 2014).

Finally, in the cases where one tip of the hydraulic fracture intersects one natural fracture at a ninety degree angle, and the other tip is surrounded by reservoir rock, the net pressure distribution and the width profile will increase slightly at the tip at the natural fracture, but most of the fluid flow will be directed toward the other end of the hydraulic fracture, the end surrounded by the reservoir. Therefore, in these cases, more propagation will occur at that hydraulic fracture tip that does not intersect a natural fracture (Wu & Olson, 2014).

Relative Angle between the Hydraulic Fracture and the Natural Fracture

The previous cases describing the effects of natural fracture configuration on hydraulic fracture propagation all assume the hydraulic fractures are at ninety degree angles with the natural fractures. When natural fractures are parallel to maximum horizontal stress, these cases are possible because hydraulic fractures propagate perpendicular to minimum horizontal stress ("Fracture Mechanics," n.d.). However, natural fractures can exist at "any strike relative to [maximum horizontal stress]," so the angle between natural fractures and hydraulic fractures can vary and have an impact on hydraulic fracture propagation (Laubach, Olson, & Gale, 2004). Figure 2 below shows how the angle between a natural fracture and a hydraulic fracture is defined. The figure shows an induced hydraulic fracture approaching a natural fracture at an angle, labeled the angle of approach. The angled shape intersecting the origin represents a natural fracture that exists at some non-ninety degree angle with the hydraulic fracture.

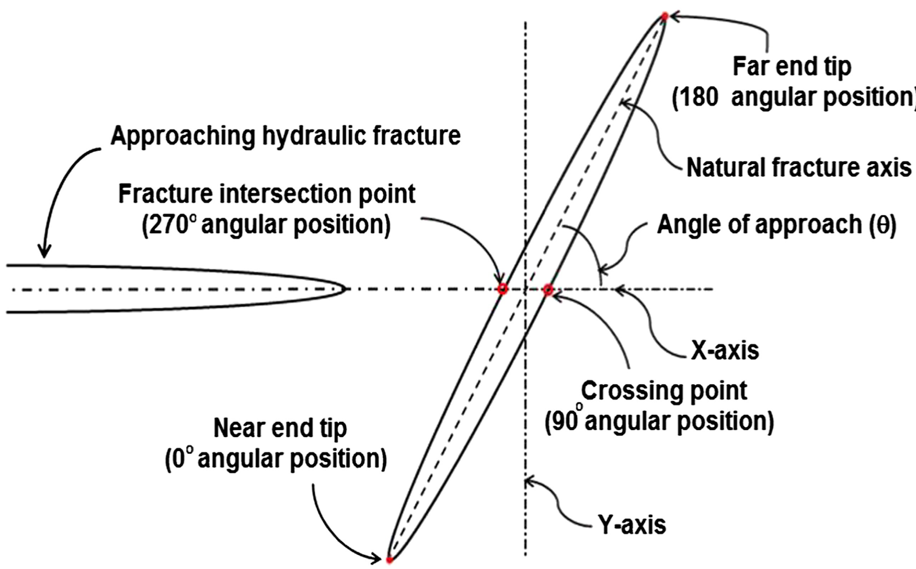

Figure 2. Defining the relative angle (the angle of approach) between a hydraulic fracture and a natural fracture (Rahman & Rahman, 2013).

When the angle between the natural fracture and the hydraulic fracture is ninety degrees, the natural fracture is activated on either side of the intersection point, and the fracture fluid will be hypothetically diverted in equal amounts to each side (Wu & Olson, 2014). However, when the relative angle between the two fractures, also referred to as the angle of approach, is not equal to ninety degrees, the natural fracture will in theory only be activated in one half of the intersection point. In the case shown in Figure 2, the natural fracture would be activated in the direction of the upper right corner, shown above the hydraulic fracture. Simulation results have shown that the smaller the relative angle between the hydraulic fracture and the natural fracture, the more the hydraulic fracture will propagate in its original direction, instead of propagating more in the direction orthogonal to its original trajectory (Wu & Olson, 2014). Experimental data from samples of hydrostone have shown that for smaller relative angles, such as thirty degrees, the natural fractures will open, but the hydraulic fracture would be less likely to cross the natural fracture because of the diverted fluid. For larger relative angles, such as sixty or ninety degrees, the hydraulic fractures were more likely to cross the natural fractures if the differential stress values were high enough to allow the hydraulic fracture to continue to propagate (Blanton, 1986).

In addition, studies have shown that less injection pressure is necessary when the relative angle between the hydraulic fracture and the natural fracture is smaller (Wu & Olson, 2014). Experimental data from tests performed on hydrostone blocks with a controlled natural fracture arrangement has shown that at smaller relative angles, the natural fracture is more likely to open and divert the fracturing fluid, or stop the propagation of the hydraulic fracture. At larger relative angles, the hydraulic fractures are more likely to cross the natural fracture (Blanton, 1982). The relative angles will affect interaction, but on an individual scale, geology and pressure are important.

Natural Fracture Length

The length of natural fractures will also affect the fracture network. In cases where the hydraulic fracture intersects the natural fracture, and then extends along the natural fracture until emerging at the natural fracture's tip, the hydraulic fracture will exit the natural fracture's tip at a kink angle, which is the acute angle formed by the emerging hydraulic fracture and the continuation of the natural fracture. A smaller kink angle indicates that the hydraulic fracture has been deflected more in the direction of the natural fracture; a greater kink angle indicates the hydraulic fracture has returned more to its original trajectory within the formation. Simulations have shown that the longer the natural fracture is, the more shallow the kink angle will be (Wu & Olson, 2014). Therefore, a longer natural fracture will cause the hydraulic fracture to deviate less from the direction of the natural fracture, and more from its own original trajectory, once it emerges from that natural fracture's tip (Rahman & Rahman, 2013). For shorter natural fractures, the kink angle will be greater. Therefore, the hydraulic fracture will more readily return to its own original trajectory.

Differential Stress

Differential stress refers to the difference between the maximum and minimum horizontal stresses in the rock (Engelder, n.d.). Results from simulations have shown that for higher differential stress values, the hydraulic fracture will propagate more in the direction of maximum horizontal stress, and the kink angle at which the hydraulic fracture emerges from the natural fracture will be greater. The hydraulic fracture is more likely to propagate in the direction of maximum horizontal stress, thus minimizing the width profile, because the differential stress is greater than those stresses created by the hydraulic fracture, and will therefore have a greater influence on the fracture geometry (Wu & Olson, 2014). At a higher differential stress, more injection pressure will be required in order to engage the preexisting natural fractures (Wu & Olson, 2014). Experimental data from tests done on hydrostone samples show that at higher differential stresses, the hydraulic fractures are more likely to cross the natural fractures. For lower differential stresses, the hydraulic fracture may deflect and continue in the path of the natural fracture, or the natural fracture may simply be forced open (Blanton, 1982).

Injection Rate

The interactions between natural fractures and hydraulic fractures as characterized previously are determined by the geology of the formation. However, these interactions can also be affected by the well completion design. At higher injection rates, the hydraulic fracture is more likely to cross the natural fracture and continue through the reservoir in the direction of its initial trajectory (Rahman & Rahman, 2013). At lower injection rates, the hydraulic fracture is more likely to be stopped, or to be deflected into the natural fracture. Therefore, the induced hydraulic fracture half length will be greater for higher injection rates (Rahman & Rahman, 2013). In addition, at a higher injection rate, the fluid leakoff from the fracture network will be overcome and the stress intensity factor at the hydraulic fracture tip will be maintained at such a level that allows the hydraulic fracture to cross the natural fracture and continue propagating into the reservoir (Rahman & Rahman, 2013). There have been some instances where a lower frac injection rate of around fifteen to twenty pounds per minute has successfully caused natural fractures to open. However, in these cases, the increase in production rates was limited, and no lasting openings were induced at these rates (Li, 2014).

Additional Well Completion Metrics

Beyond injection rate, other completions design variables can affect the interactions between natural and hydraulically induced fractures. For example, hydraulic fracture initiation points will determine how connected the total fracture network will be. Often, fracture initiation points are chosen by dividing the length of the wellbore by the number of desired stages. In any hydraulic fracture job, this strategy will be inefficient because formations are heterogeneous, so some sections may be under-fractured and others may be stimulated beyond a point of diminishing returns. King (2010) describes how fracture initiation points can be selected so as to maximize the overall effectiveness of the fracture job. Mud logging data from the drilling of the well can reveal the total methane and methane-to-ethane ratios at different portions of the lateral section. Increased gas storage indicates a section of increased porosity or the presence of natural fractures (King, 2010). In addition to using gas composition data from mud logging operations to determine the locations of natural fractures, examining the mineralogy of the cuttings can also be useful. Cuttings with more patterns of calcite streaks can indicate the presence of natural fractures that have been filled (King, 2010). Those areas of the formation with natural fractures are easier to fracture hydraulically. Initiating the hydraulic fractures in areas with more natural fractures will result in a better-connected fracture network overall, because the preexisting fracture network will enhance the additional stimulated fractures. Therefore, creating the completions design should involve a thorough analysis of the mud logging data from the drilling process so as to improve the effectiveness of the design.

In addition to the hydraulic fracture initiation point, the stage spacing can also affect the overall fracture network. In areas with more natural fracture sets, the spacing between stages can be widened so there is less overlap in the fracture network (Li, 2014). Reducing this overlap will make the hydraulic fracture job more efficient and cost-effective. Alternatively, in zones with less natural fractures, closer stage spacing will help to avoid areas of non-stimulated rock between stages. The choice of fracturing fluid can also impact how effectively linked the hydraulic and natural fractures become. Slickwater fracs are a common choice for stimulating shale formations. Compared to linear or cross-linked gels, slickwater fracs are simple and carry less proppant. According to King (2010), slickwater fracs help increase the overall fracture connectivity by breaking down fissures, micro-cracks, natural fractures, and bedding boundaries in shale. However, because slickwater fracs do not hold proppant as well as gels, slickwater can limit the flow capacity of the reservoir. In addition, sometimes more viscous fracturing fluid is necessary in order to open natural fractures that have been closed (Parker, Bazan, Tran, White, & Lattibeaudiere, 2015). In areas where natural fractures have been filled by calcite cementation, hydrochloric acid can help increase the overall connectivity of the fracture network by dissolving the fill (King, 2010). However, this dissolution can also result in plugging problems, which reduces the effectiveness of the natural fractures.

Finally, in areas where water is present and operators wish to mitigate water production, hydraulic fractures should be created such that they are located far away from potential water sources and faults that may connect the well with water (Li, 2014). In creating the completions design for a well, the overall objective is to maximize production in a cost-effective manner. Producing water is inconsistent with this goal due to disposal costs, so it is better to avoid creating hydraulic fractures in those areas with natural fractures that may be connected to faults that contain or contact water.

Variations in Natural Fractures between Shale Plays

Most shale plays are believed to contain natural fractures that have some impact on the propagation of induced fractures created during the hydraulic fracturing process (Gale, Reed, & Holder, 2007; Wu & Olson, 2014). However, the natural fractures vary greatly in terms of orientation, length, and composition between shale plays. Natural fractures are identified and characterized based on information made available from outcrop studies, seismic data, or from geophysical logs or core samples.

Natural fractures can be open, which is advantageous to hydraulic fracturing when the open fractures enhance permeability. However, fracture openness can also be disadvantageous because open fractures can allow hydrocarbons in the reservoir to migrate out of the reservoir, thus reducing the overall amount of hydrocarbons in place (Gale, Reed, Becker, & Ali, 2010). Open natural fractures can also have an adverse effect on hydraulic fracturing operations when the natural fractures decrease the stress intensity at the tip of the fracture, which disperses the stress in the induced fracture, inhibiting its growth (Bowker, 2007). Conversely, natural fractures can be sealed, which can affect hydraulic fracture propagation positively or negatively, or have no net effect on completion operations (Gale, Reed, Becker, & Ali, 2010). The opened or closed state of natural fractures affects the regional properties of the reservoir, which in turn impact the overall performance of the reservoir (Li, Xing, Liu, & Liu, 2015). Finally, natural fractures also can be rare enough in the formation that they will have a negligible impact on hydraulic fracturing operations. These kinds of differences in natural fractures, among others, can therefore cause different responses in the different shales that are hydraulically fractured. Figure 3 identifies the different major shale plays in the United States, each with different natural fractures (Li, 2014).

This paper specifically focuses on the natural fractures in the Barnett Shale of the Fort Worth Basin and the Wolfcamp Shale of the Delaware Basin. The Wolfcamp Shale is a relatively new formation to oil and gas operators, especially compared to the Barnett Shale. Therefore, fewer studies have been completed in the Wolfcamp, and because these studies are so new, even less data and research articles are publicly available. In comparison, there is more information available about the natural fractures of the Barnett. The information about the natural fractures in the Barnett is useful to operators because it helps dictate how wells are drilled, produced, and completed. As more information becomes available to Wolfcamp operators, similar changes can be made to well designs to optimize production and best exploit the potential value of natural fractures.

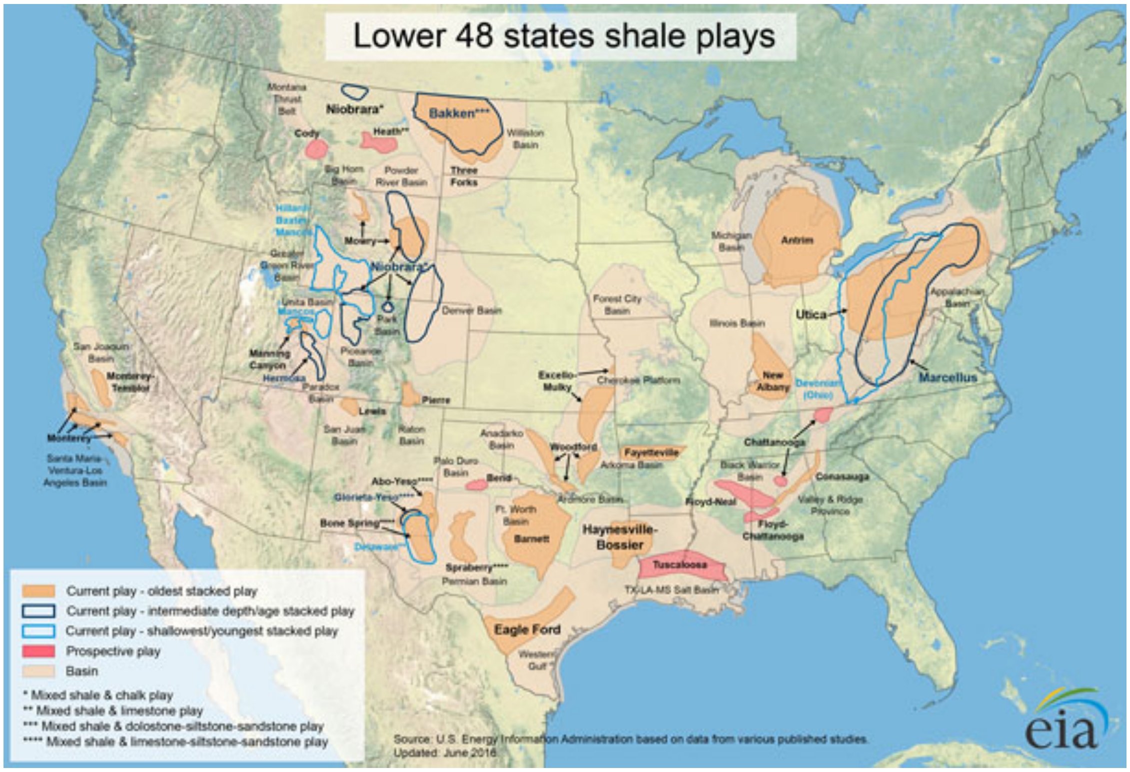

Figure 3. Lower 48 shale plays (U.S. Energy Information Administration, 2017).

Barnett Shale

The Barnett Shale in the Fort Worth Basin is a geologic formation containing natural gas reserves. The Barnett Shale contains a high frequency of natural fractures (Gale, Reed, & Holder, 2007). Hydraulic fracturing technology made commercial development of the shale possible, in part because the interactions between the natural fractures and the hydraulically induced fractures can enhance the overall effectiveness of well completions.

Gale, Reed, and Holder (2007) characterize the natural fractures in the Barnett as being common and narrow, with widths typically less than 0.05 mm, or 0.002 inches, at the widest point. The natural fractures are typically more than 1000X longer than they are wide in the Barnett. In addition, the natural fractures typically are present in echelon arrays, which means the natural fractures are generally parallel to each other but are offset, appearing as short diagonal lines contained by invisible parallel barriers (Gale, Reed, & Holder, 2007; Schlische, n.d.). With regard to mineralogy, the Barnett Shale contains a significant amount of silica, which makes the formation more brittle and thus more amenable to the development of natural and induced fractures (Gale, Laubach, Olson, Eichhubl, & Fall, 2014). However, even the layers of the Barnett that are more clay and organic matter-rich also contain a close spacing of natural fractures. Gale, Laubach, Olson, Eichhubl, and Fall (2014) attribute the natural fractures in these layers to the high TOC percentages.

Perhaps the most definitive characteristic of the Barnett Shale's natural fractures is that they are closed (Gale, 2008). Most of the natural fractures in the Barnett Shale are sealed with calcite, and thus do not serve as storage or conduits for hydrocarbons prior to stimulation. However, during hydraulic fracturing operations, these sealed natural fractures are reactivated, and reopened, which improves the overall effectiveness of hydraulic fracturing (Gale, Reed, & Holder, 2007).

Not all natural fractures in the Barnett are sealed prior to hydraulic fracturing operations; there are very few preexisting open fractures. Bowker (2007) argues that an extensive system of open natural fractures would actually have made the Barnett Shale a much less productive formation because those open natural fractures would have increased the overall formation permeability, which therefore would have allowed gas in the formation to migrate to other layers. The sealed natural fractures in the Barnett thus help trap the original gas in place. If opened, the natural fractures would also reduce the overall amount of overburden stress in the reservoir, which would make production in the Barnett more difficult. In addition, any open natural fractures would also inhibit the growth of hydraulic fractures, because in the open space, a hydraulic fracture is more likely to terminate prematurely whereas a sealed natural fracture would redirect the hydraulic fracture growth and extend its ultimate length (Bowker, 2007; Li, Xing, Liu, & Liu, 2015). Ultimately, most natural fractures in the Barnett are closed. The natural fractures in the Barnett affect hydraulic fracturing operations, and thus the overall production of the well, by reactivating during stimulation, therefore connecting the well to more of the formation.

Wolfcamp Shale

The Wolfcamp Shale in the Delaware Basin is an oil-rich shale that has become increasingly important in recent years due to the favorable economics of producing liquid hydrocarbons. Because the Wolfcamp is a relatively new target of exploration, there is less information available for this shale than there is for the Barnett. However, it is known that the Wolfcamp is a relatively heterogeneous formation (Brown et al., 2013). The Wolfcamp itself is divided into four layers, the A, B, C, and D. These layers are relatively distinct from one another, and are individually heterogeneous as well.

Whereas the natural fractures in the Fort Worth Basin tend to be steep, narrow, and closed due to being calcite-filled, the natural fractures in the Delaware Basin are more varied, reflecting this heterogeneity within each layer (Gale, Reed, Becker, & Ali, 2010). However, the natural fractures in the Wolfcamp are generally correlated with TOC. The natural fractures are concentrated in areas with higher TOC values (Gale, 2017). There are bed-parallel and vertical natural fractures in the Wolfcamp. The vertical fractures are high angle vertical, meaning they are nearly perpendicular to the surface of the earth. The bed-parallel fractures tend to form in the interfaces between rock lithologies, and are more common in the argillaceous mudstones (Ginn, Wilkins, & Liu, 2017; Gale, 2017). In terms of kinematic aperture, the high angle vertical fractures range in value from 0.004 - 0.3 inches, whereas the bed-parallel fractures range in kinematic aperture from 0.02 - 0.79 inches (Ginn, Wilkins, & Liu, 2017). Kinematic aperture refers to the opening sizes of the fractures. The high angle vertical natural fractures can be calcite filled, and can range from being "closed to partially open with patchy cement" (Ginn, Wilkins, & Liu, 2017). The bed-parallel natural fractures can be filled with calcite as well.

The dating of the natural fractures in the Wolfcamp remains a subject of debate. Ginn, Wilkins, and Liu (2017) claim that there is a "lack of primary hydrocarbon filled fluid inclusions" and "low homogenization temperatures" in the bed-parallel fractures. Fluid inclusions are the bits of fluid that become trapped in small quantities within the rock. The homogenization temperature refers to the temperature at which the fluid becomes trapped in the rock. Fractures can therefore be dated using the homogenization temperature. The supposed lack of hydrocarbon fluid inclusions and low homogenization temperatures indicate that the bed-parallel natural fractures in the Wolfcamp formed "during rapid burial in the Permian" period (Ginn, Wilkins, & Liu, 2017). Ginn, Wilkins, and Liu also claim the "homogenization temperatures of primary fluid inclusions" in the vertical fractures indicate these fractures developed later, in the late Cretaceous or early Paleogene period. Others, like Gale (2017) have disputed this timeline due to the relative lack of information available for the Wolfcamp.

Studies done in the Wolfcamp have indicated that utilizing natural fractures results in a more efficient stimulation. Brown et al. (2013) detail how the operator Endeavor Energy Resources LP strategically placed their hydraulic fracture stages in preexisting fracture zones in order to increase overall contact with the reservoir for a Wolfcamp well. The operator identified three different types of pre-stimulation fractures: open or partially-open drilling induced fractures, open and conductive natural fractures, and resistive fractures, which had once been opened but were later filled with resistive minerals like calcite or quartz, minerals which also fill the sealed natural fractures in the Barnett (Brown et al., 2013). The well was drilled in an area of the formation with high stress. The presence of natural fractures mitigates the impact of the stress, making it easier to initiate a hydraulic fracture (Li, 2014). Endeavor deliberately placed the perforations in areas where the logs indicated the concentrated presence of the drilling induced and natural fractures.

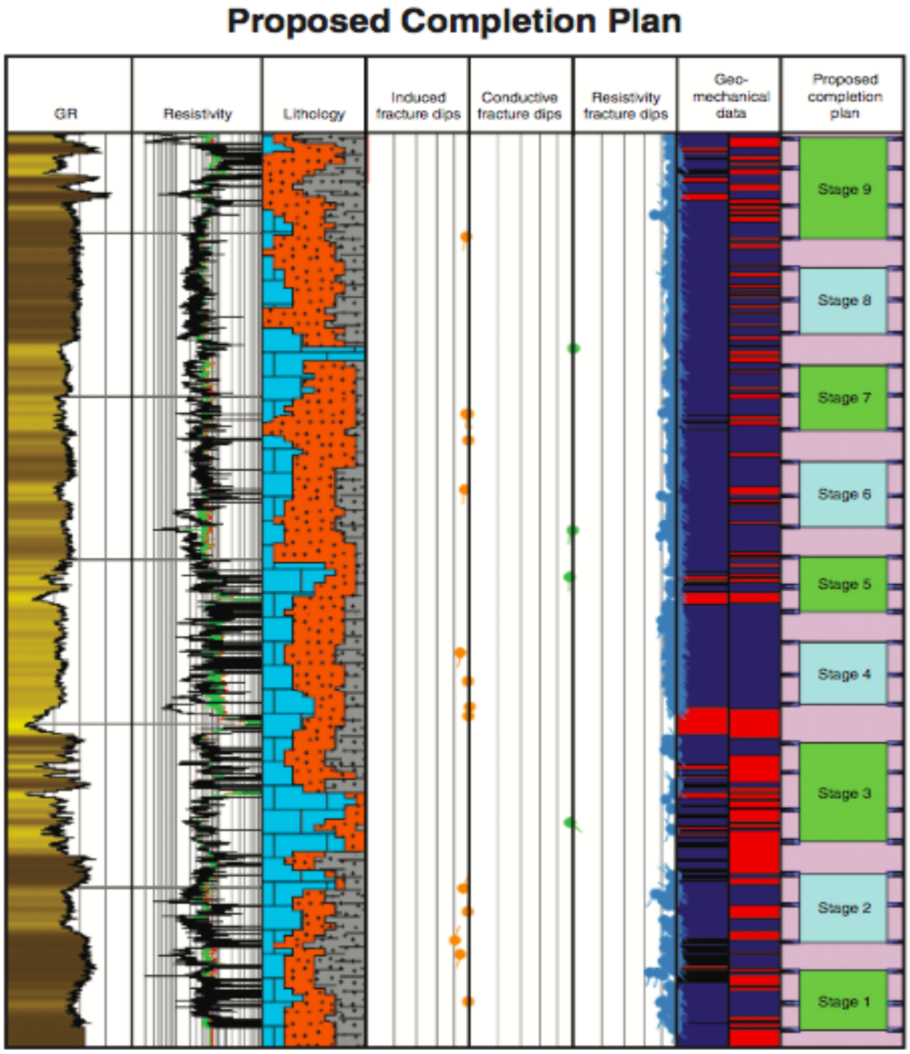

Figure 4. Completion plan for Endeavor Energy well in the Wolfcamp (Brown et al., 2013).

Figure 4 indicates the proposed locations of each frac stage in the rightmost column; the tadpole plots in the fourth, fifth, and sixth columns indicate the presence of the three different types of pre-stimulation fractures. The spacing between stages 2 and 3 and stages 3 and 4 corresponds to a lack of preexisting fractures, as indicated by the lack of points in the fourth through sixth columns at those intervals. The figure shows how the operator avoided inducing hydraulic fractures in areas where there were no preexisting fractures. According to Li (2014), this completion was successful and the adaptations to spacing improved the stimulation efficiency.

In addition to natural fractures, there are also reverse and normal displacement faults, vertical stylolites, bedding-plane slip surfaces, and septarian veins present in the Wolfcamp, and the effects of natural fractures cannot be thoroughly understood without a discussion of these features as well (Ginn, Wilkins, & Liu, 2017). In a study done in the Wolfcamp B, researchers found that the mechanical benefits of natural fractures, such as the creation of an extensive fracture network, do not occur when operators frac too near to a fault (Ouenes, Umholtz, & Aimene, 2016). There is a significant number of faults in areas of the Wolfcamp, so operators must exercise caution in planning completions so as to enhance the positive impact of natural fractures. In addition, fracturing near faults can result in fault reactivation, which can result in undesirable higher levels of water production when the fault is connected to aquifers or other water sources (Nacht, de Oliveira, Roehl, & Costa, 2010). Vertical stylolites are related to the dissolution of carbonate in some fractures (Gale, 2017). The dissolved carbonate from one fracture can reform in another fracture, and the presence of stylolites thus implies that some natural fractures may be filled. Septarian veins are an irregularly shaped vein in the shale with a mineral fill unlike that of other natural fractures (Ginn, Wilkins, & Liu, 2017; Gale, 2017). In the Wolfcamp, the septarian veins are relatively insignificant and therefore do not greatly impact hydraulic fracturing treatments.

Gale, Laubach, Olson, Eichhubl, and Fall (2014) assert that the lack of site-specific information about natural fractures is the greatest impediment to understanding how natural and hydraulic fractures combine to create extensive fracture networks. The authors describe how knowing the natural fractures' size, distribution, strength or cohesion, spatial arrangement, and extent of cementation dictates the role that natural fractures play in these networks. In the Wolfcamp, information about the fault systems and geologic features such as the sylolites and septarian veins is also important. Extensive information on natural fractures and the other relevant geologic features is not yet publicly available for the Wolfcamp Shale. However, as time goes on and more researchers and companies have access to data on natural fractures, it is reasonable to assume that operators will be able to design completions that are even more tailored to individual reservoirs and zones.

Contributions to the MultiFrac-NF Code

For my work on the Multi-Frac NF graphical user interface (GUI), I first obtained a copy of the DDM-NF code, which runs on MATLAB, and a copy of the Multi-Frac program. I worked to familiarize myself with both. I noted which variables were used in the DDM-NF code, and which separate function files loaded the relevant variables into MATLAB. For Multi-Frac, I ran example cases and noted how different inputs were entered, and observed where users had options. For example, in Multi-Frac, some data is entered into a text box whereas other inputs are selected using a button. Units can be chosen from a drop-down list for most variables.

My next objective was to identify all of the variables in Multi-Frac. I made a spreadsheet that contained one column listing all of the Multi-Frac variables and a second column listing the variables' locations in Multi-Frac, noting which tab and which subsection of the Multi-Frac GUI the variable was categorized under. Next, I identified all of the variables in Multi-Frac that were also in the DDM-NF code, and entered the DDM-NF location of those variables (which function file, which line) in a third column. Later, I added a fourth column to the spreadsheet which notes whether each variable used in Multi-Frac can be made to vary (either by layer, cluster, or stage) or is entered as a single value. This information would become helpful in integrating the DDM-NF code with Multi-Frac because some of the variables that can vary in Multi-Frac were single value inputs in the DDM-NF code. For example, porosity and permeability can be made to vary by a user-defined layer in Multi-Frac, but were entered as single values in the DDM-NF code.

I then made a second spreadsheet listing all of the variables that are loaded into the DDM-NF engine using the main function file that loads variables. These were essentially all of the variables the program requires, except those pertaining to the natural fractures and the hydraulic fractures. I listed the units for each variable that the DDM-NF code uses in a second column. The DDM-NF code uses mostly SI units, whereas in the Multi-Frac program, users can select from different SI units and field units for each variable.

Next, both spreadsheets were reviewed, and the DDM-NF code variables that would therefore need to be added to the Multi-Frac GUI were identified. Initially, those variables that could vary in Multi-Frac but were entered as single values in the DDM-NF code were going to allow for layer and stage variation in Multi-Frac NF. However, later it was decided to simplify the Multi-Frac NF code, and not allow for variation between layers, stages, and clusters in the present stage so as to remain consistent with the existing DDM-NF program.

After these details were finalized, I then began to work in earnest to design the Multi-Frac NF GUI. To do so, I used the existing Multi-Frac GUI as a template and identified the logical places to insert those variables that the Multi-Frac NF code requires to run that were not in Multi-Frac already. In particular, a new tab had to be designed to account for the natural fracture data. On the first tab of the Multi-Frac GUI, we inserted an option for the users to "turn on" the natural fracture case. We added a tab for users to input information about the natural fractures that is turned on once this button is activated. The Multi-Frac NF engine requires inputs for the natural fracture density (expressed in terms of fractures per two-dimensional area), height, length, angle of orientation, friction angle, cohesion, and the critical stress intensity factor, K_{IC}. The natural fractures tab also allows the user to specify if the natural fractures are elliptical or rectangular in shape.

The user can input as many distributions of natural fractures as he or she desires. For each distribution, a single value is entered for fracture density, with units of fractures per unit area (square meters or square feet). In addition, the user must specify the X, Y, and Z lengths of the reference grid that governs this distribution in feet or meters. A mean value and a standard deviation must be provided for the remaining variables (natural fracture height, natural fracture length, angle of orientation, friction angle, cohesion, and stress intensity factor). Using the mean and standard deviation, a normal distribution is created for each of these variables, so each set of natural fractures input by the user is a compilation of those distributions.

After designing the Multi-Frac NF GUI, I ran additional example cases in Multi-Frac. Multi-Frac generates an Excel file with each case run, and I used the output Excel file as a template to design an output Excel file for the Multi-Frac NF. I then wrote a code in MATLAB that loads the data entries from the output Excel file into the Multi-Frac NF engine. To do so, I used the MATLAB command variable = xlsread('Excel file name', Excel tab number,'cell Column-Row: cell Column-Row'). Initially, this code only allowed for the inputs to be entered in the units that the engine runs on. However, I then adapted the code to recognize the GUI entries in the user's desired unit and convert them accordingly for the engine. To do this, I first used the command [num,txt]=xlsread('Excel file name', Excel tab number,'cell Column-Row: cell Column-Row') for the cell that indicated the desired unit for every variable. I then created a series of “if” loops with nested “elseif” loops that converted each variable to the unit the engine runs on.

```
fracturingFluid.fluidDensity = xlsread('GUIdesign.xlsx',4,'J9:J9'); %kg/m3
    [num,txt]=xlsread('GUIdesign.xlsx',4,'J8:J8');
    if isequal(txt{1},'lbm/ft^3')
        fracturingFluid.fluidDensity=fracturingFluid.fluidDensity*16.0185;
    elseif isequal(txt{1},'kg/m^3')
        fracturingFluid.fluidDensity=fracturingFluid.fluidDensity;
    elseif isequal(txt{1},'lb/gal')
        fracturingFluid.fluidDensity=fracturingFluid.fluidDensity*119.826;
    end
```

Figure 5. Conversion for GUI units to engine units based on user specifications.

The figure above shows an example of how the code works for the fracturing fluid density variable. In this case, the numeric value that the user inputs would be located in cell J9 on the fourth tab of the Excel spreadsheet output by the GUI, titles GUIdesign.xlsx. The text output for the unit selected by the user would be located in cell J8 on the fourth tab of the GUI’s output Excel spreadsheet. The if loop with “else if” statements nested inside shows how the numeric value for fracturing fluid density would be modified based on the selected unit. The engine runs on the unit of kilograms per cubic meter for fluid density, so conversions with six significant figures are used to convert the value as necessary. The user would select their desired unit from a drop-down list of options, so there would be no concern of the user typing in “lbm/ft3” instead of “lbm/ft^3,” and having the if loop not run as intended as a result.

However, ultimately it was decided that JavaScript Object Notation or JSON be used in the final version of the program to link the GUI with the engine. As a result, this MATLAB code became redundant. Once the GUI and engine became linked using the JSON, I began testing the program. While running the program with different data inputs, I identified what inputs and manipulations made the program crash or run at lower speeds. The primary issues with the program involved crashes when deleting data from some cells without replacing the initial values with new inputs. The program's reservoir visualization feature was also buggy at higher natural fracture densities. I created a list documenting all of the scenarios that caused the program to crash, which will be used in debugging the code.

Conclusion

Natural fractures are a critically important but often under-considered and under-utilized element of shale reservoirs. Natural fracture formation and development is determined by mineralogy, total organic carbon, and in-situ stresses. More brittle rock with a higher total organic carbon level is more likely to have natural fractures. Natural fractures can have both positive and negative effects on hydrocarbon recovery. While natural fractures act as accumulation space and fluid pathways for hydrocarbons, they can also increase fluid leakoff, cause natural gas to dissipate, and connect the well to more water, compromising the economics of a project.

When a hydraulically induced fracture reaches a natural fracture, the induced fractured will either cross the preexisting fracture or be re-directed along the natural fracture until emerging later at the natural fracture's tip. The interactions between the natural and induced fractures are determined by the formation stress, the natural fracture's length and orientation, and some completion metrics. Natural fractures vary from reservoir to reservoir, and can be heterogeneous within a single shale formation as well. The natural fractures in the Barnett Shale are narrow, long, and filled with a calcite cement that seals the natural fractures until a hydraulic fracture "reactivates" and opens them. The natural fractures in the Wolfcamp Shale are oriented both vertically and horizontally. Some are sealed, and others are open. The Wolfcamp's natural fractures vary in terms of length and width, and there is some debate as to when they were formed.

The relative importance of natural fractures highlights the need for better simulation software that more fully characterizes the impact natural fractures have on hydraulic fracturing treatments in a reservoir. Much of the information on natural fractures that is entered into these simulators is based on estimates and generalizations, because of the lack of data available and the need to discretize information in order to simplify calculations. While these modifications may diminish the quality of the results to some degree, any encapsulation of the impact natural fractures can have on hydraulic fracture treatments is important, and enhances the quality of results relative to those from a simulation that does not consider any natural fracture variables.

As more information becomes available on how natural fractures form, develop, and interact with hydraulic fractures, researchers and operators will have more opportunities to incorporate this information to make well completions more efficient. Natural fractures may be an under-utilized resource in shale reservoirs like the Wolfcamp today, but the discovery of new information, and particularly of localized information, will help optimize well performance. Studies in the Wolfcamp have already shown how planning frac stages in areas where logs indicate a relatively high amount of natural fractures can lead to higher levels of production. In the future, operators will be able to plan their completions based on more nuanced information about the preexisting natural fractures.

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Biography

Charlotte B. Amandes was born in Houston, Texas on October 17, 1994. She grew up in Houston, and in 2013 she enrolled at the University of Texas at Austin. There, Ms. Amandes majored in Petroleum Engineering in the Cockrell School of Engineering and in the Plan II Honors Program in the College of Liberal Arts. Ms. Amandes completed her undergraduate studies in 2018, and she will begin her professional career working as a reservoir engineer for Matador Resources in Dallas, Texas in the summer of 2018.